BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, to Conduct a Biennial Review of Costs and Rates – Test Year 2013

Docket No. 05-UR-106

DIRECT TESTIMONY OF ERIC A. ROGERS

I. Introduction and Qualifications

Q Would you please state your name and your business address?

A My name is Eric Alan Rogers. My business address is 231 W. Michigan Street in Milwaukee, Wisconsin 53201.

Q By whom are you employed?

A I'm employed by Wisconsin Electric Power Company, which does business under the name of We Energies. Wisconsin Electric Power Company is a wholly owned subsidiary of Wisconsin Energy Corporation.

Q Would you please describe your educational background?

A I earned a Bachelor of Science degree in Civil and Environmental Engineering from the University of Wisconsin – Madison in 1975 and a Master of Science degree in Environmental Engineering from Stanford University in 1978. I also took course work but did not complete a degree at the University Of Washington Graduate School Of Business.

Q Are you registered as a Professional Engineer in the State of Wisconsin?

A Yes, I am.

Q Would you briefly describe your professional experience prior to joining Wisconsin Electric Power Company?

A I worked for the United States Bureau of Reclamation in Denver, Colorado as a design engineer for two years and for Battelle Pacific Northwest Laboratories in Richland, Washington as a research engineer for three years prior to joining Wisconsin Electric Power Company in 1982.

Q Would you describe your responsibilities at Wisconsin Electric Power Company?

A I began in 1982 as a forecasting analyst and I developed the residential sales forecast for several rate cases and advance plans. During the mid 1980s and early 1990s I was responsible for analyzing the cost effectiveness of proposed demand-side programs and evaluating the performance of actual demand-side programs. In the early 1990s I became responsible for the load research group and I've since performed numerous analyses of load data. In 2001 I developed the load profiling and settlement methodology that would be used for Michigan customers who select alternate energy suppliers. Around 2002 I assumed responsibilities for cost-of-service analysis and rate design. I am currently a team leader in the Regulatory Affairs and Policy Department. My responsibilities include class load analyses, revenue forecasts, cost-of-service studies and rate design.

Q Have you previously presented testimony on behalf of the applicant in other cases?

A Yes, I presented testimony on cost of service and rate design in several cases before the Public Service Commission of Wisconsin, the Michigan Public Service Commission and the Federal Energy Regulatory Commission (FERC).

II. Purpose of Testimony

Q For which utilities are you presenting testimony?

A I am presenting testimony for the electric utility and the two steam utilities: The Downtown Milwaukee steam utility (DMS), which has production facilities at the Valley Power Plant, and the City of Wauwatosa steam utility (WS), which has production facilities at the Milwaukee County Power Plant. I will present the testimony for the electric utility first followed by the steam utilities.

Q. What is the purpose of your testimony in this docket?

A. I will be presenting evidence in connection with the Company's electric and steam applications. The purpose of my testimony for the electric utility is to present and support the electric cost-of-service analyses and the electric rate design. The purpose of my testimony on the steam utilities is to present and support the steam sales forecast, steam cost-of-service unbundling analysis and steam rate designs.

III. Electric Utility Issues

A. Purpose of Testimony and List of Exhibits

Q What is the purpose of your testimony for the electric utility?

A First I will describe the electric cost allocation methods that we used. Next I will describe the inputs to our Electric Cost of Service (ECOS) model and how the allocators are used in the model. Next I will discuss the electric rate design and revenue yields. Finally, I will discuss customer impacts and embedded credits.

Q Are you sponsoring any exhibits with this testimony?

A Yes, the exhibits I'm sponsoring are listed below.

Ex.-WEPCO/WG-Rogers-4 : Electric Class Load Analysis Results and Loss Factors

Ex.-WEPCO/WG-Rogers-5: Electric Production Plant Cost Allocation Results

Ex.-WEPCO/WG-Rogers-6: Electric Fuel and Purchased Power Allocation Results

Ex.-WEPCO/WG-Rogers-7: Electric Transmission Cost Allocation Results

Ex.-WEPCO/WG-Rogers-8: Electric Distribution Plant Cost Allocation Results

Ex.-WEPCO/WG-Rogers-9: Electric Customer Cost Allocation Results

Ex.-WEPCO/WG-Rogers-10: Electric Marginal Costs

Ex.-WEPCO/WG-Rogers-11: Electric Cost-of-Service Model Inputs and Results

Ex.-WEPCO/WG-Rogers-12: Point Beach Sale Proceeds Refund

Ex.-WEPCO/WG-Rogers-13: Biomass Tax Grant Credit

Ex.-WEPCO/WG-Rogers-14: Electric Rate Design Summary

Ex.-WEPCO/WG-Rogers-15: Electric Revenue Yield Calculations

Ex.-WEPCO/WG-Rogers-16: Electric Customer Impacts

Ex.-WEPCO/WG-Rogers-17: Electric Embedded Credit Calculations

Ex.-WEPCO/WG-Rogers-18: Electric Rules and Regulations

Ex.-WEPCO/WG-Rogers-19: Electric Rate Sheets

Q The Public Service Commission of Wisconsin has issued certain filing requirements for electric rate cases. Do your exhibits respond to some of these filing requirements?

A Yes. The following is a guide to the filing requirements that are addressed in my exhibits.

Filing Requirement #4: Ex.-WEPCO/WG-Rogers-15

Filing Requirement #5a: Ex.-WEPCO/WG-Rogers-15

Filing Requirement #22: Ex.-WEPCO/WG-Rogers-15

Filing Requirement #23: Ex.-WEPCO/WG-Rogers-16

Filing Requirement #24:	Ex.-WEPCO/WG-Rogers-16
Filing Requirement #25a:	Ex.-WEPCO/WG-Rogers-11
Filing Requirement #25b:	Ex.-WEPCO/WG-Rogers-11
Filing Requirement #25c:	Ex.-WEPCO/WG-Rogers-4 & 9
Filing Requirement #25d:	Ex.-WEPCO/WG-Rogers-4 Through 11
Filing Requirement #25e:	Ex.-WEPCO/WG-Rogers-11
Filing Requirement #25f:	Ex.-WEPCO/WG-Rogers-8
Filing Requirement #25g:	Ex.-WEPCO/WG-Rogers-8
Filing Requirement #25h:	Ex.-WEPCO/WG-Rogers-4
Filing Requirement #25i:	Ex.-WEPCO/WG-Rogers-10
Filing Requirement #25j:	Ex.-WEPCO/WG-Rogers-11 (See also response to 1-PSCW-RR-20)
Filing Requirement #26:	Ex.-WEPCO/WG-Rogers-10
Filing Requirement #27:	Ex.-WEPCO/WG-Rogers-10
Filing Requirement #28:	Ex.-WEPCO/WG-Rogers-10

B. Electric Cost of Service Analysis

1. Overview

Q. Please describe the process you use for cost of service analysis.

A The cost of service analysis assists in determining the proper rates for each class of service by starting with the costs that those classes impose on the system. The analysis follows three initial steps in determining cost responsibility—functionalization, classification and allocation.

Q. Could you explain the terms functionalization, classification and allocation?

A Yes. Functionalization is the process of categorizing costs based on their function within the utility. Generally, costs are functionalized as production, transmission or distribution. Classification is the process of categorizing costs based on whether they are related to demand, energy or customers. The FERC Uniform System of Accounts is used as a guide for both functionalization and classification. Some costs, particularly general costs and overhead costs cannot be directly functionalized or classified. In general, they are functionalized and classified based on how the labor portion of operation and maintenance (O&M) costs have been functionalized and classified. Allocation is the process of assigning costs to certain groups of customers based on how these costs are functionalized and classified.

Q How do you functionalize costs?

A For the most part, the job of functionalizing plant costs is performed by our Plant Accounting Department, which operates in conformance with the FERC Uniform System of Accounts. Similarly, operations and maintenance costs are functionalized by our Finance Department, also in conformance with the FERC Uniform System of Accounts.

Q Would you describe the process for classifying costs?

A All of the costs are classified by whether they are related to demand, energy or customers. Demand-related costs are those costs that are incurred to meet customer demand for power. Energy-related costs are those costs that are incurred as customers consume energy. The fuel burned in power plants is an example of energy-related costs. Customer-related costs are those costs associated with customers regardless of the amount of power they demand or energy they consume. The cost to install a service drop is an example of customer-related costs. In general, production costs that vary with the amount of energy consumed are classified as energy-related. Production costs that do not vary with the amount of energy consumed are classified as demand-related. Transmission costs are primarily demand-related. Distribution costs are classified as either demand-related or customer-related.

Q Would you describe the allocation process?

A The purpose of the allocation process is to assign costs to the various jurisdictions and customer rate classes. Demand-related production and transmission costs are allocated based on each class's proportion of coincident peak demand (average of the 4 Summer monthly values (June, July, August and September) or 4CP or the average of 12 monthly values or 12CP), and energy-related production costs are allocated based on each class's proportion of energy. I describe class load analysis in the following section; allocation of distribution costs is somewhat more complicated and will be described later in my testimony.

Q What jurisdictions do you serve and allocate costs to?

A In addition to the Wisconsin retail jurisdiction we also serve retail customers in the state of Michigan. In addition, we serve wholesale customers in both Wisconsin and Michigan, subject to regulation by the Federal Energy Regulatory Commission.

2. Electric Class Load Analysis

Q Could you briefly describe the class load analysis that is used to derive demand allocators?

A Our class load analysis provides estimates of each class's load at the time of each monthly system peak and at the time of each class's annual non-coincident peak. The data used for this analysis is derived from interval load data from either a census of customers or statistical samples of customers. The samples are designed to provide a 90/10 level of confidence and precision for the annual system peak hour. This means that there is a 90% probability that our estimate of each class's load at the time of our system peak is within 10% of the actual load at that time. We check the accuracy of our class load analysis by summing up our estimates of all the class loads and comparing the total to the known system load. Generally, the total of our estimates is within plus or minus 2% of the known system load.

Q What years of the class load analysis are used to derive the demand allocators?

A Any given year will have weather anomalies that could distort the normal relationship between energy and demand, so we use an average of five years of class load analyses to derive the demand allocators. For this filing we used 2006 through 2010. The results of the class load analysis are shown in Ex.-WEPCO/WG-Rogers-4.

Q Ex.-WEPCO/WG-Rogers-4 also shows loss factors. What are these used for?

A The metered data we use for the class load analysis is at customer level, while the known system load data is at the transmission interface. The difference between transmission level and customer level are the distribution losses. We use the same loss factors for energy and demand. While we understand the losses vary somewhat with system load, this variation is not extreme. It would not be appropriate to apply the loss factor at the time of the annual system peak for the 12CP calculation because the 12CP is the average of the 12 monthly system peaks, eleven of which are considerably lower than the annual system peak. Likewise, the noncoincident peaks generally occur at times when the system load is considerably lower than the annual system peak. We believe that using the same loss factors for energy and demand is reasonable; as indicated earlier, the sum of our estimates of class loads at the time of system peak matches the known system peak quite closely. The distribution loss factors were originally derived from a comprehensive loss study performed in 2004 using 2003 data. The values were adjusted slightly at the behest of PSCW staff in Docket 05-UR-104.

3. Allocation of Production Plant Costs to Customer Classes

Q Have you prepared a cost-of-service study to functionalize, classify and allocate costs to your electric jurisdictions and classes?

A Yes. I have prepared one jurisdictional cost of service study according to FERC and jurisdictional practices. I have also prepared six different versions of our class cost-of-service study. The scenarios differ in the way production plant and related costs are allocated to customer classes within the Wisconsin retail jurisdiction. The demand, energy and customer allocators are detailed in Ex.-WEPCO/WG-Rogers-4. The allocators used for production plant costs are detailed in Ex.-WEPCO/WG-Rogers-5. The allocators used for fuel and purchased power costs are detailed in Ex.-WEPCO/WG-Rogers-6. The allocators used for transmission O&M costs are detailed in Ex.-WEPCO/WG-Rogers-7. The allocators used for distribution plant costs are detailed in Ex.-WEPCO/WG-Rogers-8. The allocators used for customer-related costs are detailed in Ex.-WEPCO/WG-Rogers-9. The marginal capacity costs for calculating non-firm credits are detailed in Ex.-WEPCO/WG-Rogers-10. All of the other inputs to the model and the model results are detailed in Ex.-WEPCO/WG-Rogers-11. The total company column of Ex.-WEPCO/WG-Rogers-11 Schedule 1 ties out to the income statement for the total company presented by Company witness Mr. David Ackerman in Ex.-WEPCO/WG-Ackerman-1 Schedule 6.

Q In previous rate cases, the Company provided a single class cost-of-service study. Why are you providing more than a single cost-of-service study in this case?

A We are providing multiple versions of the cost-of-service study, with each version varying the method used to allocate production plant to customer classes. The PSCW staff briefing memorandum in Docket 05-EI-137 dated August 17, 2006 describes various methods for allocating costs to customer classes, and we agree that no one method is considered the "correct COSS", although I do believe there is a range of acceptable methods. In other words, not every cost of service study necessarily provides a valid result. The various cost-of-service studies we have performed provide points on a range of reasonable results. Each point on the range reflects differences in the amount of costs allocated to one class of customers versus another class of customers. We used one of these cost-of-service studies as the starting point, or base case, for the rate design.

Q. How do you assess whether a particular study is valid for inclusion in the range of reasonable results?

A. First, the methods used should be consistent with commonly accepted theoretically sound practices. In addition, the method must be consistent with the specific operational characteristics of the system being studied. Next, the data to support the analysis must be reasonably available and reliable. Finally, I don't believe that a dramatic change to a method should be made too quickly. The cost of service study provides a measurement of changes in class rate design, and if dramatic changes to the study are employed too quickly, then assessment of the proper design will be more difficult. As in other matters before this Commission, gradualism is important in making changes.

Q. Would you please summarize the results of the multiple cost of service studies you are providing?

A. Yes. As I indicated, what distinguishes the cost of service studies from one another is the method used to allocate production plant costs to customer classes. In addition to a base case, we looked at four alternative ways of allocating production plant costs. The fifth alternative also reflects a modification to the allocator used for fuel and purchased power costs. The table below summarizes the results:

Impact on Customer Classes of Various Methods to Allocate Production Plant Costs

Method	EP 12CP	EP 4CP	100% Dem 12CP	100% Dem 4CP	LMP Energy for Plant	LMP Energy for Plant, Fuel & PP
Scenario in Ex. Rogers-15	Alt 1 (B)	Base Case (A)	Alt 2(C)	Alt 3 (D)	Alt 4 (E)	Alt 5 (F)
Prod Plant Classification						
Demand	50%	60%	100%	100%	50%	50%
Energy	50%	40%	0%	0%	50%	50%
Demand Allocator	12CP	4CP	12CP	4CP	4CP	4CP
<u>TY2013 Revenue Deficiency</u>						
Small Customer Class	6.09%	7.38%	7.60%	9.28%	7.34%	7.86%
Medium Customer Class	-4.08%	-3.95%	-3.80%	-3.65%	-3.37%	-3.25%
Large Customer Class	2.00%	0.83%	0.30%	-1.18%	0.84%	0.25%
SLO Customer Class	0.75%	-13.30%	-2.56%	-22.34%	-15.23%	-16.81%
Total Company	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%

Note: Revenue deficiency is without incremental fuel and with the biomass tax grant credit.

Q Can you explain the table?

A. The table shows the Test Year 2013 revenue deficiency by customer class using our base case method and five alternatives. They differ in the manner in which we allocate production plant costs. (Note that the revenue deficiency percentages shown do not include incremental fuel costs, which we are treating as a separate cost in this proceeding but do include the proposed biomass tax grant credit.)

Q. Please describe the differences among the alternative class cost studies.

A A major factor is the use of alternative measures of demand and energy, and the amount of production plant that each is applied to. I began by establishing a base case, and then I developed results of each alternative study. For each alternative, I initially intended to change only one parameter relative to the base case; however, the final base case we developed has a different split between energy and demand for the allocation of production plant costs, so each alternative has two parameters that are different than the base case. The alternatives shown have variations in treatment of production plant, as well as any other allocators that are derived from production plant allocation. It is important to note that all other methods of allocation are the same in each study. These methods—for transmission, distribution, general plant and most O&M expenses—are described below and again, are consistent among the 6 alternatives presented.

Q. What demand and energy data are the bases for the various production plant allocations you looked at?

A Our base case uses the average coincident peak demand for the four summer months of June, July, August and September (4CP) to allocate the demand portion of production plant costs to classes within the Wisconsin retail jurisdiction. The energy portion is allocated with total transmission-level energy.

Q Why are you supporting 4CP to allocate the demand-related portion of production plant, instead of 12CP, which was used in the past?

A The National Association of Regulatory Utility Commissioners "Electric Utility Cost Allocation Manual" (NARUC Manual) describes the 12CP method on page 46. It states, "This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky." For many years this described our load shape, but over the course of the past few decades the difference between our summer peaks and winter peaks have become more pronounced. Although what we've argued in the past, (that we must plan for capacity in all twelve months of the year), is still true, our summer peaks are clearly the primary determinant of our capacity planning.

Q Please describe the alternative allocation methods you examined.

A Alternatives 1, 2, and 3 address the allocation of production plant costs we classify as demand-related. Alternative 1 uses the equivalent peaker methodology and classifies production plant costs as both demand- and energy-related. That portion classified as demand-related is allocated using 12 CP (in contrast to 4CP in the base case). Alternative 2 classifies production plant costs as 100 percent demand-related and allocates those costs using 12CP. Alternative 3 also classifies production plant costs as 100 percent demand-related and allocates those costs using 4CP.

Q What about your Alternatives 4 and 5?

A These two alternatives address the allocation of production plant costs we classify as energy-related. As noted, the base case and Alternatives 1 through 3 involve the allocation of the demand-related portion of production plant costs. Energy costs are treated the same in the base case and Alternatives 1-3 (using the total energy allocator for production plant and on-peak and off-peak energy allocators for fuel and purchased power). Alternatives 4 and 5 modify that energy allocation as I describe here.

We are aware that others in the state have considered an allocator for the energy-related portion of production plant costs that is instead weighted by hourly LMP. While we believe that this approach has merit, we did not include it in our base case because of the difficulty of developing the allocators such that they are consistent with the test-year forecast. For illustration purposes, however, we have developed estimates of LMP-weighted energy allocators based on our estimates of historical hourly class loads and actual historical hourly LMPs, as reported by MISO. We used the same five years of history that was used to derive the ratios for the demand allocators detailed in the class load exhibit, Ex.-WEPCO/WG-Rogers-4. Weighted LMP allocators were developed for total energy, on-peak energy and off-peak energy for each of the five years and the five years were averaged. The allocators were then adjusted based on the class energy forecast in the test year. The results of this analysis were used to allocate the energy-related portion of production plant costs in Alternative 4. Alternative 4 is our base case as modified to use weighted LMP allocators for the portion of production plant classified as energy. A logical extension of this method is to also use the LMP weighted energy allocators for fuel and purchased power costs (except for the purchased power cost associated with the Point Beach Nuclear Plant PPA, which have prescribed costs for both on-peak energy and off-peak energy and do not vary with LMP). Thus, Alternative 5 is best understood as our base case, modified to use weighted LMP allocators for the portion of fixed production plant classified as energy as well for fuel and purchased power costs.

Q. Does Wisconsin Electric support any particular methods for allocating the cost of production plant?

A. There is no scientifically “correct” answer to the question of how to allocate production plant costs. The various approaches have pros and cons. What we have done is to investigate several of the possible approaches and present the results to the Commission for its consideration. The table that appears earlier shows the impact of each approach on customer classes as percentages of revenue deficiency. Ex. –WEPCO/WG-Rogers-11 shows the impacts in dollar terms. We used the base case as the starting point for rate design.

Q. You referred earlier to a “range of reasonable results”. Can you expand on that concept?

A Yes. The range of reasonable results I discussed above for the allocation of demand-related production plant costs is illustrated in the first four columns of the table. Moving from left to right, the small class has progressively larger revenue deficiency and the large class has progressively smaller revenue deficiency. As discussed earlier, the last two columns (Alternatives 4 and 5) show the impacts of using an LMP-weighted energy allocator on the base case. The LMP-weighted energy allocator also could be used with Alternatives 1 through 3. My table does not show the results of doing so.

Q. What conclusions should the commission draw from your multiple cost of service studies?

A. I believe the base case is appropriate for initial rate design guidance. The Commission could use the alternatives I have described in final rate design now or in the future. That would not be inconsistent with my view of appropriate cost analysis.

4. Allocation of Production Plant Costs to Jurisdictions and Separation Into Demand-Related and Energy-Related Components

Q How are production plant costs allocated to the Wisconsin retail jurisdiction?

A Historically (including Docket 05-UR-104) production plant costs have been allocated to jurisdictions based on the 12-month average coincident demand, or 12CP. This is consistent with filing requirements in FERC cases and the Michigan Public Service Commission has recently approved the use of 12CP for the allocation of production plant costs to jurisdictions (Case U-15500). The use of a consistent allocator for all three jurisdictions ensures that production plant costs are fully recovered in one jurisdiction or another. We are allocating production plant costs to jurisdictions based on 12CP.

Q What method did you use in your cost-of service model to allocate production plant costs to classes within the Wisconsin retail jurisdiction?

A. We used the equivalent peaker method to split production plant costs into demand-related and energy-related components. This is the method that best fits the theory that base load and intermediate load plants are built to provide less expensive energy, as well as providing capacity. The derivation of this equivalent peaker method result is shown on Ex.-WEPCO/WG-Rogers-5. As indicated in Ex.-WEPCO/WG-Rogers-5, the equivalent peaker method result is roughly equivalent to allocating 50% of the production plant costs based on demand and 50% on transmission-level energy. In the last rate case, docket 05-UR-104, these values were calculated as roughly 60% demand and 40% energy. The reasons for the change are the reduction of the estimated cost to build a new combustion turbine and substantial increases in the investment in wind plant, which provides energy without adding a lot of capacity. This seems like a rather substantial change from one rate case to the next, so for our base case we used the 60/40 demand to energy split derived by the equivalent peaker analysis from docket 05-UR-104, but for all the alternative scenarios we used the 50/50 demand to energy split derived by the current equivalent peaker analysis.

Q What parameter is used to allocate the energy portion of production plant costs to the classes within the Wisconsin retail jurisdiction?

A. The energy-related portion of production plant costs is allocated to classes with total transmission-level energy, which is derived in Ex.-WEPCO/WG-Rogers-4.

Q Did you make an adjustment to your production plant cost allocation to account for non-firm loads?

A. Yes. A production plant cost credit is applied to classes with non-firm loads. The production plant cost credits are based on the cost of a combustion turbine, which is detailed in Ex.-WEPCO/WG-Rogers-10 Schedule 1. The credits are allocated to jurisdictions and classes based on their non-firm demand. The cost of these credits is then allocated to jurisdictions and classes based on the total of their firm and non-firm demands. We will continue to use the cost of a combustion turbine as a proxy for the value of capacity (at least for the purpose of cost allocation) until a more robust capacity market develops.

5. Allocation of Fuel, Purchased Power and Variable O&M Costs

Q How do you allocate fuel and energy-related purchased power costs to jurisdictions and classes?

A To the extent possible, we split fuel costs and energy-related purchased power costs into on-peak and off-peak costs and then allocate to jurisdictions and classes based on transmission-level on-peak and off-peak energy. Costs that are not readily categorized by on-peak and off-peak are allocated based on total transmission-level energy. These costs are shown in Ex.-WEPCO/WG-Rogers-6. The exhibit shows both current costs and deferred costs. The deferred costs related to the MISO start-up are directly assigned to the Wisconsin retail jurisdiction.

Q How do you allocate the demand-related purchased power to jurisdictions and classes?

A Demand-related purchased power is allocated to jurisdictions on 12CP and to classes based on 4CP.

Q How are the costs for the Point Beach Nuclear Plant purchase power agreement allocated to jurisdictions?

A In Docket 05-UR-103, the Commission ordered that the PBNP PPA costs be allocated to jurisdictions based on 65% demand and 35% energy. We are proposing to continue using 65% demand and 35% energy for the jurisdictional allocation of Point Beach Nuclear Plant purchase power agreement costs.

Q How are the costs for the Point Beach Nuclear Plant purchase power agreement allocated to classes within the Wisconsin Retail jurisdiction?

A Order Point 33 in Docket 05-UR-103 specified that we develop a method that reflects how Point Beach costs were allocated to retail customer classes prior to the sale. Our analysis, presented in Docket 05-UR-104 indicated that the effective allocation factors were 60% demand and 40% energy. The order in Docket 05-UR-104 was silent on this point so we are using this same split in this Docket.

Q In Docket 05-UR-103, a credit was approved for refunding the proceeds of the sale of the Point Beach Nuclear Plant, and this credit was adjusted in Docket 05-UR-104. The credit expired at the end of 2010. The final order in Docket 05-UR-103 indicated that the Company shall use escrow accounting for the Point Beach Nuclear Plant credits. Is this escrow accounting of the Point Beach Nuclear Plant credit reflected in the revenue requirement in this case, and, if so, how is it allocated to the classes?

A. The balance for the Point Beach Nuclear Plant credit is a regulatory asset and is treated as other operating revenue, as shown in the Company's response to the pre-filed data request PSCW-RR-29. The value shown in PSCW-RR-29, $1,292,000, is half of the total account balance of $2,584,000 because the rates approved in this Docket are expected to be in effect for two years, so the Company will recover half the value in each of the two years. The allocation of the Point Beach Nuclear Plant credit regulatory asset is documented in Ex.-WEPCO/WG-Rogers-12.

Q How are production operations and maintenance costs, other than fuel and purchased power costs, allocated to jurisdictions and classes?

A Production O&M costs are classified as either demand-related, energy related or supervision and engineering. Demand-related costs are allocated to jurisdictions based on 12CP and to classes based on 4CP. Energy-related costs are allocated to jurisdictions and classes based on transmission-level energy and supervision and engineering costs are allocated to jurisdictions and classes in proportion to the labor allocated in the other production O&M accounts. The derivation of the labor allocator is described in Ex.-WEPCO/WG-Rogers-11.

Q How are Power the Future (PTF) lease costs allocated to jurisdictions and classes?

A Power the Future (PTF) lease costs are allocated to jurisdictions based on 12CP, just as other production plant. Adjustments are made to account for different accounting methods in each jurisdiction. On a class basis, PTF expenses are allocated to classes in a similar way as production plant. The equivalent peaker method is used to determine which part of the PTF lease payment should be allocated on 4CP demand. The remainder is then allocated on energy. The derivation of the equivalent peaker allocator values is shown in Ex.-WEPCO/WG-Rogers-5.

Q An adjustment is made to the cost-of-service study for the biomass tax grant and a credit will appear as a line item on customers' bills. How is this credit allocated to the jurisdictions and classes?

A. The biomass tax grant is allocated to jurisdictions and classes in the same manner as total production plant. This is 12 CP for the jurisdictions and the equivalent peaker results for classes.

6. Allocation of Transmission Cost

Q How are transmission plant costs allocated to the Wisconsin retail jurisdiction?

A Transmission charges from the American Transmission Company and the Midwest Independent System Operator (MISO) are treated as operations and maintenance costs in our cost-of-service model.

Q What costs are included in your transmission O&M costs?

A Transmission O&M costs include the charges we receive from the ATC and MISO. These costs are directly passed through to our customers without any markup (as are all O&M costs). Also included in the transmission O&M costs are costs deferred in Wisconsin that we incurred in prior years but have not yet recovered.

Q How are transmission O&M costs allocated to jurisdictions?

A First of all, the amortization of Wisconsin deferred transmission costs relating to the startup of MISO and ATC are directly assigned to the Wisconsin retail jurisdiction as shown in Ex.-WEPCO/WG-Rogers-7. Transmission O&M costs beyond the deferrals are allocated to jurisdictions based on a 12CP coincident demand. For most of the transmission costs, WPPI, GLU, MGE and Cloverland are excluded from the 12CP allocator because these customers contract for transmission services separately. There are some transmission costs that should be borne by all customers, including these FERC MISO participants, and these costs are listed on Ex.-WEPCO/WG-Rogers-7.

Q How are transmission O&M costs allocated to classes within the Wisconsin retail jurisdiction?

A Most transmission O&M costs are billed to the Company by MISO and ATC on the basis of coincident demand, but a small portion is billed on the basis of energy as shown in Ex.-WEPCO/WG-Rogers-7. Transmission O&M costs are allocated to customer classes using this functionalization allocator. Demand-related transmission costs are allocated to customer classes with 12CP and energy-related transmission costs are allocated to customer classes with total transmission-level energy.

7. Allocation of Distribution Plant Cost

Q How are distribution plant costs allocated to the Wisconsin retail jurisdiction?

A All our distribution plant is identified by the state in which it is located, and for the most part the cost of a given piece of equipment is directly assigned to the retail jurisdiction of the state it is located in. There are some adjustments, however. There are a few substations along the border between Wisconsin and Michigan that serve retail customers in both states. The costs for these particular substations are allocated to the two jurisdictions in proportion to our estimate of the demand of the retail customers on these particular substations. These values are shown in Ex.-WEPCO/WG-Rogers-8 Schedule 1. Also, within Wisconsin there are a few substations and feeders that serve Wisconsin

Public Power, Incorporated (WPPI) customers. The costs for these particular facilities are also allocated to either the Wisconsin retail jurisdiction or the FERC jurisdiction based on demand. These values are shown in Ex.-WEPCO/WG-Rogers-8 Schedules 10 and 11.

Q How are distribution operations and maintenance costs allocated to jurisdictions and classes?

A The distribution O&M costs for substations, overhead feeders, underground feeders, line transformers, meters, installations on customer premises and street lighting are identified for Wisconsin and Michigan. A portion of each State's distribution O&M costs is allocated to the FERC jurisdiction based on distribution plant. Distribution O&M costs are allocated to classes based on the allocators for the respective plant costs. Dispatching costs are allocated based on noncoincident demand (NCP). Supervision, engineering and miscellaneous distribution O&M costs are allocated to jurisdiction and classes in proportion to the sum of all other distribution O&M costs. The values for these allocators are listed in Ex.-WEPCO/WG-Rogers-11.

Q Would you describe in more detail how distribution costs are classified?

A. The distribution system is built to meet two criteria. It must connect to all customers and it must be capable of handling the load at the time of the peak demand of the customers connected to it. The costs of connecting to the customers are classified as customer-related costs. The assumption is that there would be costs associated with serving customers even if they only used a minimal amount of energy (or even no energy at all). We would install the smallest conductors and the smallest transformers and the smallest poles and the smallest equipment needed to serve the minimal use customers. We have determined the cost to install the hypothetical smallest size of each type of equipment.

The unit cost for the smallest piece is then multiplied by the total number of pieces of equipment on the system to calculate the customer-related costs. When we have sufficient data we use the minimum-intercept method to determine the customer-related costs. This involves developing regressions of cost versus size and then using the intercept cost value as an indication of the hypothetical cost of serving a customer with zero load. When we do not have sufficient data to perform regressions, we use the minimum-sized method. This involves identifying the least expensive item installed on our system. Both the minimum-sized and minimum-intercept methods are described in the NARUC Manual, on pages 90 and 92, respectively. Equipment that is larger than the minimum size is installed to support the load demanded by the customers, so the incremental costs associated with the larger size are classified as demand-related. The difference between the total distribution costs and the customer-related costs are classified as demand-related costs.

Q How are substation costs (plant accounts 360 and 361) allocated to customer rate classes?

A Substation costs are allocated to customer classes based on noncoincident demand (NCP). As indicated in the NARUC manual on page 90, substations are built to serve load regardless of the number of customers. The NCP demand values are derived from Ex.-WEPCO/WG-Rogers-4.

Q How are feeder costs (plant accounts 364, 365, 366 and 367) allocated to customer rate classes?

A There are about 2,000 distribution feeders on our system. Only a few hundred of these feeders serve primary customers. Almost all of the feeders, however, serve residential and general secondary customers. If our distribution system had been designed to serve only primary customers, we would have only needed to build those few hundred feeders that currently serve the primary customers. If, on the other hand, our distribution system had been designed to serve only residential and single-phase general secondary customers, the system would have to be virtually identical to what it is today. It is appropriate, therefore, that the residential and single-phase general secondary customers pay a portion of the costs for all the feeders that they use (virtually the entire system), while the primary customers should only pay for a portion of the few hundred feeders that they actually use. In this analysis we have further defined the distribution system to differentiate between the three-phase system and the single-phase system. Feeders originate at substations in three-phase configuration. Primary customers and three-phase general secondary customers (and the very rare three-phase residential customers) are served from the three-phase portion of the feeders. Many feeders eventually split into three single-phase lines in order to serve the more geographically dispersed residential and small general secondary customers. These single-phase lines do not serve the primary and large general secondary customers, and therefore should not have these costs allocated to them. This differentiation between single-phase and three-phase feeders is a refinement of our methodology (compared to that used in our previous rate case – Docket 05-UR-104). For this analysis, we assume that single-phase lines have two conductors (a single primary conductor plus a neutral) and three-phase lines have four conductors (three primary conductors plus a neutral).

Q How were the costs for each feeder estimated?

A We have conductor data from two sources. Our geographical information system (GIS) mapping system lists the feeder conductors' lengths by size, material, type (overhead or underground), phase (single or three) and installation date for each feeder, but it does not indicate the costs. Our Plant Accounting database lists conductors' lengths and costs by size category, material, type and installation date, but it does not indicate the feeder. Total inflated feeder costs are estimated by applying the average inflated cost of the conductors as determined from the plant accounting data to the conductor lengths indicated in the GIS data. For overhead, the costs include the costs of poles. The total conductor lengths from the two data sources are fairly consistent. The Plant Accounting data lists 89,700 conductor miles and the GIS data lists 55,500 primary conductor miles.

Q How are the customer-related and demand-related costs for each feeder determined?

A. The conductor sizes are categorized in the Plant Accounting data into just three categories, so we do not have sufficient cost data to perform a regression to determine the minimum-intercept cost for conductors. We use the minimum-size method. A review of the data indicated that the least expensive conductor installation costs about $11,065 per conductor-mile (after inflating costs to 2013 terms using the Gross Domestic Product Industrial Production Deflator Index). As explained above, the customer-related costs in theory should be those costs that are associated with connecting the customer with the system and not any costs associated with serving any load. We know that the minimum-sized conductor installed in the field was designed to carry some load. We assume that 50% of the cost of the minimum-sized conductor is demand-related and the other 50% of the cost is customer-related. The customer-related cost used for all conductors in our analysis, therefore, is $5,533 per conductor mile. The demand-related costs are determined simply by subtracting the customer-related costs from the total estimated cost for each feeder.

Q How are the costs of each feeder allocated to the customer classes?

A. The customers served by each feeder are identified from data extracted from our Outage Management system. The annual energy of each customer is derived from our billing system. The NCP for each customer is derived by multiplying the annual energy for each customer by the ratio of NCP to annual energy, as determined by our class load analysis. The demand-related costs for each feeder are then allocated to each customer class proportionally to the total NCP of the given class on the feeder. The customer-related costs are allocated to each customer class proportionally to the number of customers served by the feeder. We do not have feeder identification for street lighting accounts, so we assume each feeder has the same proportion of street lighting NCP as determined by the class load analysis. The street lighting allocation percentage based on NCP is also used to allocate customer-related feeder costs to street lighting, as it is difficult to define street lighting 'customers'. The allocation of feeder costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedules 2 and 3.

Q How are the costs of secondary mains allocated to customer classes?

A. The proportion of overhead and underground conductor costs that represent the secondary mains is listed in Ex.-WEPCO/WG-Rogers-8 Schedule 12. This same proportion is applied to both the customer-related and demand-related portions of conductor costs. Secondary mains serve most residential customers and small and medium general secondary customers. Therefore, the large general secondary values are excluded from both the customer and demand allocators.

Q How do the results of this feeder analysis compare to those presented in your last rate case, Docket 05-UR-104?

A For the most part, the results of this analysis are quite similar to those we presented in the last rate case. The percent of costs attributed to the secondary system in this case is slightly more than that of the last case for both overhead and underground. The percent of demand-related costs in this case are slightly higher for both overhead (72.6% compared with 70.1%) and underground (90.4% compared with 87.4%). There are very slight changes in the results for the allocation of demand-related costs among the classes. For overhead, there is a small increase in the demand-related costs allocated to the small customer class (78.7% in this case compared to 73.5% in the last case) and for underground, the percent of demand-related costs allocated to the small customer class are lower in this case than they were in the last case (68.2% in this case compared with 69.9% in the last case). The methodologies used in the two analyses are similar (except for the differentiation of single-phase and three-phase feeders), but the raw data are, of course, different. The quality of the GIS data continues to improve with time and the identification of relationships between feeders is improved.

Q. Could you elaborate on how the transformer costs (plant account 368) were allocated to the classes?

A. Yes. Transformer costs are essentially directly assigned to the classes because we know which transformers serve which customers. The allocation of transformer costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedule 4.

Q. Could you elaborate on how the service drop costs for plant account 369 were allocated to the classes?

A. Yes. We can estimate the number of service drops used by each customer class by assuming that customers with the same service address, excluding apartment number or suite number, share the same service drop. This analysis is done by customer class rather than rate schedule because it is possible that a single service drop could serve customers on both the flat and time-of-use rates. It is less likely that a single service drop would serve both small and large customers. Costs for plant account 369 are then allocated proportionally to this estimated number of service drops for each customer class. The allocation of service drop costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedule 5.

Q. Could you elaborate on how the meter costs for plant account 370 were allocated to the classes?

A. Yes. Meter costs can essentially be directly assigned to the classes because we know which meters serve which customers. We can add up the number of meters serving each class, taking into account the fact some customers, particularly larger customers, have more than one meter. Our metering service people have provided estimates of the unit costs for meters serving different classes. It is understandable why a three-phase meter with interval data collection capabilities serving a large industrial account would cost more than a single-phase energy meter serving a flat-rate residential account. Allocation factors for each class are then derived by multiplying the number of meters in each class by the estimated unit cost of meters in each class. Costs are then allocated to customer classes proportionally to these allocation factors. The allocation of meter costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedule 6.

Q. Could you elaborate on how the installations on customer's premises and leased property on customer premises costs for plant accounts 371 and 372 were allocated to the classes?

A. Yes. Costs for installations on customer premises and leased property on customer premises are allocated to customer classes based on our plant accounting records. Plant account 371 consists of area lighting and refrigeration systems. The area lighting plant is allocated to the Wisconsin and Michigan street lighting and other classes based on the energy forecast. All of the refrigeration plant is allocated to the Wisconsin general primary class. Plant account 372 consists entirely of transformers used by the Wisconsin general primary class. The allocation of 371 costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedule 7 and the allocation of 372 costs is shown in Ex.-WEPCO/WG-Rogers-8 Schedule 8.

Q. Could you elaborate on how the miscellaneous costs for plant accounts 360 and 361 are allocated to the classes?

A. Yes. The miscellaneous distribution costs are allocated to the classes based on the proportion of all the other distribution costs allocated to the various classes.

Q. Would you describe how customer advances for contributions in aid of construction (FERC account 252) are allocated to the jurisdictions and classes?

A. Yes. Contributions in aid of construction are payments that customers make to us when we install new distribution lines to serve them. Sometimes other new customers use these lines as well, and when that happens the original customer may be reimbursed for the payment. In our model these payments are allocated to jurisdictions and customer classes based on the costs of the overhead and underground distribution systems.

Q. The distribution system in the State of Wisconsin serves wholesale customers as well as retail customers. How are the distribution system costs allocated to these wholesale customers?

A. The substations and feeders that serve our wholesale customers (who are not part of the Wisconsin retail jurisdiction) were explicitly identified, and the costs of those explicitly identified components were estimated. The loads for both the wholesale customers and the retail customers on each of the explicitly identified components were determined with metered data. The estimated costs of those components were allocated to either the wholesale jurisdiction or the retail jurisdiction based on the noncoincident peak demand of the particular component. The details of these calculations are shown in Ex.-WEPCO/WG-Rogers-8 Schedules 10 and 11.

8. Allocation of Customer Costs

Q How are customer costs categorized?

A Customer costs are defined by FERC accounts 901 through 916. We categorize accounts 901, 902, 903 and 905 as customer accounting costs. Account 904, uncollectibles, is handled separately. We have no costs in account 906. Accounts 907 through 910 are categorized as customer service costs, but the conservation escrow portion of account 908 is handled separately. Accounts 911 through 916 are categorized as sales costs.

Q How are these customer costs allocated to jurisdictions?

A Our budgeting process develops test year budgets separately for Wisconsin and Michigan. The TY2013 budget split between Wisconsin and Michigan is consistent with historical actual splits. We make a small adjustment to the customer accounting and customer service costs to account for expenses incurred for customers in our FERC jurisdiction (our historical actual and budget forecast data does not identify costs for the FERC jurisdiction). We assume there are no uncollectible costs for the FERC jurisdiction. The derivation of the jurisdictional allocators for customer costs is shown in Ex.-

WEPCO/WG-Rogers-9. This exhibit also addresses regulatory commission costs and miscellaneous administrative and general costs.

Q How are these customer costs allocated to classes within the Wisconsin retail jurisdiction?

A Departments and work groups within the company prepare budgets each year. Many work groups focus on a particular customer class. For example, the call center has a work group that handles calls from residential customers and another work group that handles calls from general secondary customers. The industrial billing work group only concerns itself with large general secondary and general primary customers. We look at these budgeted costs and assign them to classes. For the customer accounting and customer service costs, categorizations that include customers in more than one class are split into classes based on customers. A fairly small portion of the total customer cost budget defies categorization in this manner. These costs are also assigned to classes in proportion to customers. A letter dated December 20, 2008 from PSCW Chairman Callisto to the Governor and State Legislature recommended that costs for conservation programs be directly assigned to classes at which they are targeted. We assume that this supersedes the PSCW Order in Docket 05-UR-101 that half the costs should be allocated on demand and the other half should be directly assigned to the targeted class. Conservation escrow programs that include customers in more than one class would be split into classes based on 4CP demand. Costs for Act 141 payments to the State Administrator are allocated 30% to the residential class and 70% to non-residential classes. The State Administrator in our service territory bases this on recent expenditures. Costs for Act 141 large customer refunds are directly assigned to the large customer class.

This will result in higher future refunds for qualifying large customers (and consequently a larger escrow for these funds in future rate cases). The impacts of the Act 141 large customer refunds are not reflected in the revenue yield calculations because of the escrow accounting we use for them. Residential uncollectible costs are directly assigned to the residential class. Nonresidential uncollectible costs are spilt between general secondary and general primary classes based on revenue. The derivation of the class allocators for customer costs is shown in Ex.-WEPCO/WG-Rogers-9. Schedule 1 shows forfeited discounts in FERC account 450. Schedule 2 shows customer accounting costs in FERC accounts 901, 902, 903 and 905. Schedule 3 shows uncollectibles in FERC account 904. Schedule 4 shows customer service costs in FERC accounts 907 through 910, excluding the conservation escrow in FERC account 908. Schedule 5 shows the conservation escrow in FERC account 908. Schedule 6 shows sales expenses in FERC accounts 911 through 916.

Q How are Act 141 unit costs that are embedded in base rates calculated?

A The calculation of Act 141 costs that are embedded in base rates is shown in Ex.-WEPCO/WG-Rogers-9 Schedule 5. The unit costs are calculated simply by dividing the total costs allocated to each customer group by the forecasted customer-level energy. For this calculation, the customer groups are defined as residential and non-residential. The unit embedded cost for non-residential customers will be used to calculate refunds (or charges) for large customers who qualify. There is no need to calculate the unit Act 141 costs that were embedded in rates in 2005. Our process for calculating refunds (or charges) for qualifying large customers is based on the particular customer’s actual contribution in 2005.

9. Allocation of Administrative and General Costs

Q How are administrative and general costs allocated to jurisdictions and customer classes?

A Administrative and general costs are defined by FERC accounts 920 through 935. Most of these costs are allocated to jurisdictions based on how the labor portion of O&M is allocated to the classes, as the majority of the A&G costs are related to labor, including pensions and benefits. Property insurance, FERC account 924, is allocated based on property. Regulatory commission expenses, FERC account 928, are specifically budgeted for each jurisdiction and are allocated to classes based on revenue. General plant is allocated to classes based on how the labor portion of O&M costs is allocated. Some of these costs are detailed in Ex.-WEPCO/WG-Rogers-9. Schedule 7 shows the company's internal regulatory commission costs in FERC account 928. Schedule 8 shows miscellaneous administrative and general expenses in FERC account 930.

10. Allocation of Depreciation Reserve and Depreciation Expenses

Q How are depreciation reserve and depreciation expenses allocated to jurisdictions and classes?

A Depreciation reserve and depreciation expenses are allocated to jurisdictions based on the same allocators used for the gross plant values of the respective components.

11. Allocation of Income Taxes

Q How are income taxes, deferred income taxes and accumulated deferred income taxes allocated to jurisdictions and classes?

A The components that make up income taxes, deferred income taxes and accumulated deferred income taxes are functionalized by our tax department as being related to production, transmission, distribution, or general. Each of the functionalized components are allocated to jurisdictions and classes based on their respective gross plant values. Taxes for each class are then calculated from these allocated components. The State of Michigan has recently implemented two new income taxes. We calculate a composite state income tax rate using the rates from each state with an apportionment based on sales. The values for these allocators are listed in Ex.-WEPCO/WG-Rogers-11.

Q Could you briefly describe the computer model you use for your cost-of-service study?

A Yes. In the past we used a proprietary Electric Cost of Service (ECOS) model developed by Future Scope, Incorporated. In testimony in the last rate case, Docket 05-UR-104, we described an EXCEL model that we developed which uses the same inputs and provides the same outputs as the Future Scope Model. We shared this model with interveners and Commission Staff in the last rate case with some success. For this rate case we have improved upon the EXCEL model, and now we no longer use the Future Scope model. The inputs and outputs of the model are shown in Ex.-WEPCO/WG-Rogers-11.

Q Could you describe Ex.-WEPCO/WG-Rogers-11?

A Yes. Ex.-WEPCO/WG-Rogers-11 is presented in five main sections, each with several schedules. The sections correspond to jurisdiction, functionalization, classification, class and subclass allocations. The jurisdiction, class and subclass sections start with a schedule showing the summary reports of the cost-of-service analysis. This is followed by another schedule showing the detailed reports. These two reports show the same information and indeed are derived from the same worksheets. The only difference is the summary report has many detail lines hidden. The functionalization and classification sections have only the detailed reports. Following the reports, there are schedules that show the allocator assignments and the allocator or direct assignment values. The allocator assignments indicate what allocator is used for every account input to the model. Allocator values are presented in separate schedules for the external allocators, internal allocators and labor allocators.

12. Summary Cost of Service Study Results

Q What are the results of the cost-of-service study, in terms of revenue deficiency for the major customer classes in the Wisconsin retail jurisdiction?

A The results of our base-case cost-of-service study indicate a total revenue deficiency of $224,575,464, or 8.12% in TY2013 for the Wisconsin retail jurisdiction after excluding the costs of the biomass and solar plants and costs the company intends to manage. This is the revenue deficiency upon which our TY2013 rate design is based. Excluding fuel costs (including the expiration of the credit from the settlement with DOE over the dry cask storage issue), the revenue deficiency is 6.24%. After applying the credit for the biomass tax grant, the effective revenue deficiency without fuel impacts is 3.59% in TY2013. These results are shown in Ex.-WEPCO/WG-Rogers-11. Schedule 1 shows a summary and Schedule 2 shows details of the jurisdictional separation study. The deficiency used for rate design is $155,416,820 or 11.38% for the small customer class, $523,294 or 0.27% for the medium customer class, $71,857,962 or 6.08% for the large customer class and -$3,222,612 or -11.11% for the street lighting and other class. The summary and detailed results for the classes are shown in Ex.-WEPCO/WG-Rogers-11 Schedules 18A and 19A, respectively.

C. Electric Rate Design

Q Are you proposing adjustments to the current electric rates?

A Yes. We are proposing to implement new base rates that would be effective on January 1, 2013 (or upon final approval by the Commission). We are also proposing an adjustment to base rates, effective January 1, 2014, to recover costs associated with the biomass and solar plants that are expected to come on line in late 2013. We are also proposing to provide a credit for the biomass tax grant as a separate line item on each bill. This credit would be based on total energy. Most of the credit would be returned to customers in 2013 and the credit would be adjusted in 2014 to return the remaining amount. Effective on January 1, 2015, this credit would expire. We request escrow accounting for this credit, in the same manner as that approved by the commission in Docket 05-UR-103 for the Point Beach Nuclear Plant credit. Any over or under return would be trued up in a subsequent rate case. The derivation of the biomass tax grant credits is shown in Ex.-WEPCO/WG-Rogers-13. All our proposed rate designs are summarized in Ex.-WEPCO/WG-Rogers-14. The revenue yield for the current rate designs and the proposed rate designs are compared in Ex.-WEPCO/WG-Rogers-15. The percentage increases for each rate is also shown in Ex.-WEPCO/WG-Rogers-15. All the billing determinants used to calculate the current and proposed revenue yields are also shown in Ex.-WEPCO/WG-Rogers-15. This is in response to Filing Requirement 4.

Q Per Filing Requirement #22, could you describe how the results of the cost-of-service model were used to develop the rate design?

A The results of the cost-of-service model would normally be used as guidelines for the rate design. In theory, if all of the assumptions used in our cost-of-service model were accurate, the results would define the rate design that provides the most proper price signals possible to our customers. It would not be the optimal rate design, however. It is impossible to develop an optimal rate design because the billing components we use to bill our customers are different than the components we use in our cost-of-service model. For example, the cost-of-service model uses 4CP and class noncoincident peak for the demand allocators, but our customers are billed based on monthly on-peak demand and ratcheted all-hours demand. Although correlated, these demand concepts are not identical. Another major difference between the cost-of-service analysis and the rate design is the fact that cost-of-service is an analysis of the average embedded costs and rate design uses marginal costs. Marginal demand costs, based on the cost of a combustion turbine, are less than average demand costs, while marginal energy costs, based on MISO's locational marginal price (LMP), are often higher than average energy costs (although in this analysis, marginal energy costs are lower than embedded energy costs – a most unusual circumstance). This normally has the effect of shifting demand-related costs to energy charges. Rate design considers many factors in addition to the cost-of-service. As discussed earlier the cost-of-service study in this docket had two methodology changes from that used in our previous rate case. These two methodology changes are the use of 4CP to allocate demand-related production costs and the differentiation between three-phase and single-phase distribution systems. One tenet of rate design is rate stability. Therefore, the Commission may consider phasing in the impacts of these methodology changes over a number of rate cases. When performed consistently over time, the cost-of-service study allows the Commission to track the impact of other factors.

Q How is the 8.12% requested revenue relief distributed to the classes for the purposes of the rate design?

A As noted above, the results of the cost-of-service model, shown in Ex.-WEPCO/WG-Rogers-11 Schedules 18 and 19 Line 36 (or Row 320), indicate that the total requested revenue relief of 8.12% is distributed to classes as 11.38% for the small customer class, 0.27% for the medium customer class, 6.08% for the large customer class and -11.11% for the street lighting and other customer class. Normally these cost-of-service model results would be used as guidelines for the rate design. As discussed earlier, however, the cost-of-service study in this docket had two changes from that used in our previous rate case. These two changes are the use of 4CP to allocate demand-related production costs and the differentiation between three-phase and single-phase distribution systems. Both of these changes have the effect of shifting costs out of the large customer class and into the small customer class. One tenet of rate design is rate stability. The cost-of-service study was used as the starting point for the rate design process. Other adjustments are made in the course of rate design, so the final revenue changes for each class do not match these adjusted cost-of-service study results. For example, one consequence of using 4CP to allocate demand-related production costs is the street lighting and other class is allocated very little of these costs because lights are generally not on during the summer peaks. The final percent increases with our proposed rate design in TY2013, with the incremental fuel costs and without the biomass tax grant credit, are 9.27% for the small customer class, 5.31% for the medium customer class, 7.38% for the large customer class and 2.21% for street lighting and other. Excluding the incremental fuel costs and including the biomass tax grant, the percent increases with our proposed rate design in TY2013 are 5.32% for the small customer class, 1.09% for the medium customer class, 2.13% for the large customer class and -0.06% for the street lighting and other class.

Q Why do you combine residential and small general secondary customers into one group?

A The cost drivers for residential and small general secondary customers are similar. Current energy charges for the respective schedules (Rg1 and Cg1, and Rg2 and Cg6) are identical. It is appropriate that the price signals for these customers be consistent. Having consistent price signals avoids controversy over whether a particular customer is on the appropriate rate.

Q Why do you combine the large general secondary customers with the general primary customers?

A The differentiation between Cg3 and Cp1 is at the customer's discretion. Any Cg3 customer could, theoretically, switch to Cp1 and vice-versa (although the minimum demand requirement for Cp1 makes such a switch impractical for many Cg3 customers). The largest Cg3 customers have load patterns (and thus cost drivers) that are very similar to Cp1 customers. A large price discrepancy between Cg3 and Cp1 provides an incentive for some Cg3 customers to switch to Cp1. Some customers may not be prepared to accept the responsibilities that come with the Cp1 rate. In order to eliminate such perverse price signals, it is appropriate to design the Cg3 and Cp1 rates in conjunction with each other.

Q What are the appropriate differences between the Cg3 and Cp1 rates?

A There are three appropriate differences between the Cg3 and Cp1 rates. The first difference relates to the cost of losses. Because Cp1 customers receive their energy at higher voltage, the losses associated with their energy are lower. This should be reflected in both energy and demand charges. The second appropriate difference between the Cg3 and Cp1 rates is the line transformer costs. Cp1 customers own their own transformer, so their rates should not reflect the costs of company-owned line transformers. Cg3 customers, on the other hand, receive their energy downstream from a company-owned line transformer, so their customer demand charge should reflect this cost. The third appropriate difference between Cg3 and Cp1 rates is the fact that Cp1 has a power-factor adjustment and Cg3 does not. This requires more complex metering and billing systems for Cp1. These additional costs are reflected in the facilities charge.

Q Why is Cg2 in a separate category?

A The Cg2 rate is meant to be a transition between Cg1 and Cg3.

Q Could you describe the approach you used for designing the rates for the small customer group?

A Yes. First we calculated the facilities charge. The facilities charge is based on metering costs, service drop costs, customer accounting costs, customer service costs and uncollectibles. We call these the 'base' customer costs. Note that these 'base' customer costs do not include all of the costs that were classified as customer-related costs in the cost-of-service study. Weighted averages of these costs are developed for both single-phase and three-phase customers. Based on this review, we are proposing to increase the facilities charges from \$0.25/day and \$0.50/day for single-phase and three-phase customers, respectively, to \$0.35/day and \$0.70/day, respectively. At these levels, the 'base' customer costs are recovered by the facilities charges, but the total customer-related distribution costs are still not completely recovered by the facilities charges. The flat energy rate is then derived by dividing the remaining costs (total costs minus the base customer costs) by the total forecasted energy for these classes. The on-peak and off-peak rates for Rg2 and Cg6 are developed such that the ratio of on-peak charge to off-peak charge is about 5.2 for the level 2 option, and the break-even point between the flat rate and time-of-use rate is at about 62% off-peak energy and 38% on-peak energy (without considering facilities charges). The resulting off-peak rate for Rg2 and Cg6 is above the average off-peak marginal energy cost. This ensures that the Company will recover sufficient revenue in the off-peak period to cover marginal costs.

Q Could you describe the approach you use to develop the energy charges for the Rg2 voluntary time-of-use rate?

A Yes. Analysis of our load patterns indicates that flat-rate residential customers use about 38% of their total energy during the on-peak period. The purpose of time-of-use rates is to provide an incentive for customers to shift some of their load to the off-peak period. Our residential rates can be considered a family of rates, with Rg1 being the premium rate that provides steady service at a predictable rate. Rg2 Level 1, with a proposed ratio between the on-peak price to the off-peak price of 2.2, offers residential customers the opportunity to save a little with some small load shifting with the risk that bills could be a little higher if the customer fails to shift load. Rg2 Level 2, with a proposed ratio between the on-peak price to the off-peak price of 5.2, offers the opportunity for more savings at a slightly higher risk. Our proposed rate design for both the Level 1 and Level 2 Rg2 time-of-use options are designed such that a customer would break even if 38% of total energy was consumed on-peak. It is important that this break-even point be the same for both options.

Q Could you describe the approach you use to develop the energy charges for the Rg3 experimental time-of-use rate?

A Yes. The Rg3 three-tiered time-of-use rate is designed such that the revenue would break even with the Rg1 flat rate at approximately 38% on-peak usage, similar to the Rg2 rates, although this is a more complicated analysis, given the Rg3 rate has two on-peak periods and seasonal rates.

Q Could you describe the approach you used for designing the rates for the large customer group?

A Yes. Again the facilities charges are set to roughly cover the costs of the 'base' customer costs. Our analysis indicated that the current charges for primary customers are close to these 'base' customer costs, so no changes are proposed to facilities charges for primary customers. We are proposing to increase facilities charges for large general secondary customers from $1.52877/day to $1.8000/day for Cg3 and from $3.41918/day to $3.6/day for Cg3C and Cg3S At these levels, the 'base' customer costs are recovered by the facilities charges, but the total customer-related distribution costs are still not completely recovered by the facilities charges.

The customer demand charge is intended to recover the demand-related portion of the distribution system. In the previous rate case, Docket 05-UR-104, we noted that the customer demand charge does not recover all of the demand-related distribution costs. Based on the results of our cost-of-service study, this is still true, so we are proposing modest increases in the customer demand charges for both secondary and primary customers. We are proposing to increase the medium voltage primary customer demand charge from $1.007/kW to $1.510/kW. At this level, most of the demand-related distribution costs are recovered by this charge. The main difference between the primary and secondary demand-related distribution costs is the cost of the line transformers. This cost is approximately $0.50/kW, so we are proposing secondary customer demand charge of $1.972/kW, which is an increase from the current charge of $1.757/kW. Any remaining demand-related distribution costs are recovered by the energy charges.

The billed demand charges for large customers are normally set to approximately the marginal capacity cost for production and transmission. The marginal transmission cost is based on charges from ATC and MISO and are shown in Ex.-WEPCO/WG-Rogers-10 Schedule 3. These charges have increased substantially since our previous rate case (Docket 05-UR-104). The marginal production cost is based on the construction cost of a combustion turbine, which is documented in Ex.-WEPCO/WG-Rogers-10 Schedule 1. This value is slightly lower than it was in Docket 05-UR-104. We noted at the time of the filing in that previous case that we expected the construction cost of a combustion turbine to decrease, and we also noted anecdotal evidence that the contract price of purchased capacity would be much lower than the cost of constructing a new combustion turbine. Therefore, we did not use the calculated cost of a combustion turbine as the basis for the billed demand charges in that docket; rather we used the value from the previous case, Docket 05-UR-103. The calculated value of a combustion turbine shown in Ex.-WEPCO/WG-Rogers-10 Schedule 1 is somewhat higher than the value calculated in Docket 05-UR-103. The proposed billed demand charges in this case are substantially higher than the current billed demand charges because both the transmission cost component and the production cost component have increased, relative to what the current billed demand charges are based upon.

The remaining production, transmission and distribution costs are recovered through on-peak and off-peak energy charges, which are set at a level to recover these costs with on-peak and off-peak rates proportional to on-peak and off-peak marginal energy costs, which are substantially lower than in previous cases. The proposed energy charges, therefore, are only slightly different than the current energy charges (comparing the sum of the base energy charges and the fuel cost adjustments).

The energy and demand charges for the large customer group are adjusted to account for losses; secondary rates are slightly higher than primary rates and lower voltage levels within the primary class have slightly higher rates than higher voltage levels.

Q Could you describe the approach you used for designing the Cg2 rate?

A Yes. As mentioned above, the Cg2 rate is intended to be a transitional rate between Cg1 and Cg3. The billed demand charge is set to be about half way between that of Cg1 (or zero) and that of Cg3. The production portion of the energy charge is calculated by dividing the remaining production costs by the energy. The distribution portion of the energy charge is also set between the Cg1 distribution energy charge and Cg3 distribution energy charge. The on-peak / off-peak energy charges are designed to break-even with the old flat-rate option. Note that the old flat-rate option is no longer available for Cg2 customers.

Q The Cg2, Cg3, Cg3C and Cg3S rates have an adjustment to the demand charge for customers with low load factors. Could you explain the purpose of this and how it is calculated?

A Yes. The demand charge is applied to the maximum 15-minute consumption during the on-peak period. If a customer has an unusually large spike in load for a short duration, this would create a peak demand that is not representative of the customer's normal load. The probability that this spike would occur at the time of our system peak is fairly low, and, therefore, it would not necessarily add to the company's capacity costs. For this reason, our rate structure provides a reduction in the demand charge for secondary customers with monthly hours of use below 100. The amount of the credit has historically been set to about 0.6% of the demand charge for every hour of use below 100.

Q How were the credits for existing non-firm programs and rates (Cg3C, Cg3S, Cp3, Cp3S and CpFN) calculated?

A In the past, the capacity credits for non-firm programs and rates were based on the marginal cost of generation capacity for a combustion turbine. In Docket 05-UR-104, we argued that the market price for capacity is well below this level, and the Commission agreed to close these non-firm options to new customers because of this situation. The market for contingency reserves, however, has developed in recent years, and the contingency reserve value can be applied to certain non-firm loads. The derivation of non-firm credits is shown in Ex.-WEPCO/WG-Rogers-10 Schedule 5 using both the cost of a combustion turbine and the cost of purchased capacity. The current non-firm credits are between these two derivations. For rate stability, we propose maintaining the current non-firm credits. The energy charge discount for CpFN non-firm load is set to about 5% in this rate design.

Q Are you proposing any changes to your non-firm tariffs?

A Yes. Order point 23 of the order dated December 18, 2009 in the last rate case, Docket 05-UR-104, authorized the Company to close non-firm rates to new customers. Testimony from both the Company and PSCW Staff in that case indicated that the reason for this is due to the current over-supply of capacity in the region; new non-firm load would not be beneficial to the operation of the system. We would like to clarify the tariffs to define the term "customer" as individual accounts. The Company has many customers with multiple accounts, and some of these accounts are firm and some are non-firm. A customer with both firm and non-firm accounts should not be allowed to increase our non-firm load by converting a firm account to a non-firm account, especially when it is unlikely that the load will be curtailed at any time in the next several years.

Q Can you describe the approach you used for designing the lighting rates?

A Yes. In previous rate cases, lighting rates are designed to recover the cost of supplying the power used by the lights and, in those cases where we own the lights, the cost of the lights and related O&M. The cost of supplying power was estimated from the cost-of-service study and applied to the estimated kWh usage of each light. The revenue requirements of providing the lights and related O&M were allocated over the lights based on the annualized cost of a new light and O&M. As discussed previously, the move from using 12CP to 4CP to allocate production-plant and related costs to the customer classes within the Wisconsin retail jurisdiction resulted in a large percentage decrease in the costs allocated to the street lighting and other class. In this docket we propose to maintain the current levels of lamp charges for all the lighting schedules that have such charges. The total revenue from the street lighting and other class will still rise slightly because some of the tariffs have energy charges linked to Cg1 or Cg6.

Q Are you proposing any changes to conditions of delivery for the lighting rates?

A Yes. Several minor changes to conditions of delivery for lighting rates Ms1, Al1 and St1 are noted on the tariff sheets in Ex.-WEPCO/WG-Rogers-19

Q Are you proposing to include the total cost of fuel in the base rates?

A No. The incremental fuel cost and the expiration of the credit for the DOE settlement on dry cask storage are included in our proposed fuel cost adjustments. In the order in Docket 6630-FR-103, dated January 5, 2012, the credit for the dry cask storage settlement was used to offset increased fuel costs, so the expiration of the credit can essentially be considered a fuel-cost increase. The values for these two items are listed in Ex.-WEPCO/WG-Ackerman-1 Schedule 1 and total $51.998 million. As indicated in the application for this Docket, the fuel costs indicated in this filing are preliminary, and we will provide a more definitive estimate later in the year as updated information becomes available. Isolating the fuel cost impacts in the fuel cost adjustment, rather than embedding them in base rates, will facilitate the adjustments later.

Q What is the fuel cost that is included in the proposed base rates?

A The total fuel cost monitored under the current fuel rules under PSC 116 is $989,634,211 and the net output is 29,788,173 MWH. The unit monitored fuel cost is, therefore, $0.03322 per kWh, as indicated in Ex.-WEPCO/WG-Wolter-1 and also noted in Ex.-WEPCO/WG-Rogers-6. The fuel costs recovered by the proposed fuel cost adjustment average $0.00205 per kWh, so the fuel cost embedded in base rates is $0.03117/kWh. Fuel costs detailed in Ex.-WEPCO/WG-Rogers-6 include non-monitored fuel costs as well.

Q Have you calculated the marginal generation capacity cost?

A Yes. The value of marginal generation capacity costs has been calculated and is shown in Ex.-WEPCO/WG-Rogers-10 Schedule 1. This is in response to Electric Filing Requirement #28. As discussed in the section on demand charges, we believe the value calculated for marginal generation capacity costs may be unreasonably high.

Q Have you calculated the marginal energy generation costs?

A Yes. The five-year forecast (2013 through 2017) of marginal energy generation costs differentiated by on-peak and off-peak periods and by season are shown in Ex.-WEPCO/WG-Rogers-10 Schedule 2. This is in response to Electric Filing Requirement #26. The results are also used as a guide in developing the on-peak and off-peak energy rates and for our CGS buy-back rates.

Q Have you calculated the marginal distribution plant costs, per filing requirement 27?

A Yes. The marginal distribution plant costs are shown in Ex.-WEPCO/WG-Rogers-10 Schedule 4.

Q Are the marginal cost values you discussed in Ex.-WEPCO/WG-Rogers-10 used in rate design?

A Yes, some of the marginal cost values in Ex.-WEPCO/WG-Rogers-10 are used in our rate design. The on-peak and off-peak energy charges for time-of-use rates are set to a level slightly above the average on-peak and off-peak marginal costs, respectively. The non-firm credits for curtailable and interruptible rate schedules would be derived directly from these marginal costs, as shown in Ex.-WEPCO/WG-Rogers-10 Schedule 5 (except we are proposing no changes to non-firm credits in this Docket). We propose to use the actual bid price for purchased capacity in 2013 as the basis for this marginal generation cost rather than the cost of building a combustion turbine, as we've used in the past. Marginal capacity costs are used to derive the capacity credit for the CGS3 rate, as shown in Ex.-WEPCO/WG-Rogers-10 Schedule 7. Again, we propose to use the actual bid price for purchased capacity in 2013 as the basis for this marginal generation cost rather than the cost of building a combustion turbine, as we've used in the past. Marginal capacity costs are also used for the calculation of the Cp4 standby charge, as shown in Ex.-WEPCO/WG-Rogers-10 Schedule 8. We propose to use the estimated cost of building a combustion turbine for the Cp4 stand-by charge calculation, as we've used in the past.

Q Could you elaborate on the way the customer-owned generation buy back rates are calculated?

A Yes. Starting in 2011, the CGS1 energy buy back rates are based on daily LMP values. For CGS3 the MISO market-clearing price for purchased capacity in 2013 is used as the basis for the capacity credit, rather than the cost of building a combustion turbine, as we've used in the past. The CGS3 energy buy-back rate for company-dispatched energy flowing into the distribution system (generation in excess of the customers' on-site consumption) is based on the average of the forecasted marginal costs of the highest 300 hours in 2013 and 2014. For company dispatched displaced energy (that is energy generated by the customer and consumed by the customer on-site) the CGS3 buyback rate is calculated by subtracting the proposed on-peak firm energy rate from the CGS3 rate for energy flowing into the distribution system. This recognizes the fact that if the customers were not generating this energy they would be purchasing it from the company at the firm rate. We make no distinction between such activity during on-peak or off-peak periods. The CGS3 rate for energy flowing into the distribution system during times when it is not being dispatched by the company is set to the average of 2013 and 2014 off-peak marginal energy cost, as indicated in Ex.-WEPCO/WG-Rogers-10 Schedule 2. All these calculations are shown in Ex.-WEPCO/WG-Rogers-10 Schedule 7, which responds to filing requirement 25i.

Q Could you describe how the Energy for Tomorrow premium is calculated?

A Yes. Based on the results of our cost-of-service study, we have isolated the renewable and non-renewable production costs. The Energy for Tomorrow (EFT) premium is based on the difference between these two costs, plus the administrative costs for the program. The implicit assumption is that the EFT customers are purchasing a slice of our renewable system, rather than specific purchased power, as we have assumed in the past. The derivation of the Energy for Tomorrow premium is summarized in Ex.-WEPCO/WG-Rogers-10 Schedule 6.

Q Could you describe how the Cp4 standby rates were developed?

A Yes. The development of the Cp4 standby rates is shown in Ex.-WEPCO/WG-Rogers-10 Schedule 8. The reserve demand charge is based on the marginal capacity cost of the 14.5% reserve margin that the company must maintain to serve these customers on a stand-by basis. Standby service also requires dedication of the transmission system, so a portion of the marginal transmission costs is added to the demand charge. The standby energy charge is based on our out-of-pocket costs plus 10%. Our out-of-pocket costs are based on MISO’s locational marginal price (LMP) adjusted for losses. When this rate was first developed, LMP was somewhat higher than today; the current low prices were not envisioned. LMP is often lower than the base energy charges, so the way the tariff is currently written, the stand-by energy charges are effectively zero. This can lead to a perverse situation where it could be less expensive for a customer to be billed on Cp4 than on Cp1, even though they are receiving the additional service provided by Cp4. To remedy this, we propose to increase the minimum standby energy charge from zero to $0.03000/kWh on-peak and $0.02000/kWh off-peak.

Q Are you proposing any changes to the standby provisions of Cp1?

A Yes. We are proposing a new condition of delivery for Cp1 that specifies load normally served by the customer's own generation is excluded from the maximum measured demand and the Company shall not be required to provide standby service for that load. Also, we are proposing to eliminate the existing condition of delivery that addresses auxiliary service, as it would become moot.

Q Are you proposing any new tariffs in this Docket?

A Yes. In addition to the biomass tax grant credit discussed previously, we are proposing a new tariff option for primary customers to receive Supervisory Control and Data Acquisition (SCADA) information directly from the billing meters in real time. This would allow customers to link our meters directly to their energy management systems. A one-time fee would cover the costs of meter interface modifications. There would be no additional monthly fees for this service, as it would not affect the Company's metering or billing functions.

Q Are you adding any new lamp size options to lighting tariffs?

A We are adding one new category of flashers to the Ms1 tariff. LED technology offers very low wattage flashers, so we are proposing a tariff for flashers of 25 watts or lower. The old category of 75 watts and lower is now defined as 25 watts to 75 watts. We are also adding several LED lamp sizes for the Al1 tariff.

Q Are you proposing changes to the customer-owned generation tariffs?

A Yes, we are proposing several changes to our customer-owned generation tariffs. Major changes would affect CGS1, CGS2, CGS6 and CGS3 and minor changes would affect CGS1 and CGS7. We are also proposing a new CGS8 tariff.

Q What changes are you proposing for CGS2?

A The current CGS2 tariff allows flat-rate customers with either one meter or two meters. Time-of-use customers on CGS2 must install a second meter. Currently about half the customers on CGS2 have one meter and the other half have two meters. We propose to limit the CGS2 tariff to existing flat-rate customers with a single meter. (This tariff was closed to new customers effective January 1, 2010. We would like to clarify the tariff to define the term "customer" as individual accounts, as discussed previously.) Current CGS2 customers with two meters would be switched to either CGS6 if their generation source is renewable or CGS7 if their generation source is non-renewable. Making this change will facilitate a more efficient billing process by ensuring that all customers on a given tariff have a similar metering configuration. All CGS2 customers would have a single meter and all CGS6 and CGS7 customers would have two meters. All of these tariffs, CGS2, CGS6 and CGS7 are net-metering tariffs. There would be no impact to the customer by switching from CGS2 to CGS6 and there would be no impact to the customer of switching from CGS2 to CGS7 so long as the customers' consumption exceeds their load, as was intended when these tariffs were originally developed.

Q What changes are you proposing for CGS6?

A We propose to close the CGS6 tariff to new accounts. The original intent of the CGS6 tariff was to allow customers to install renewable generation to offset their load. Net metering was allowed in order to reduce a barrier to market entry. The tariff allows payment to customers when their generation exceeds their load, but this was intended for occasional and incidental situations. We have at least one customer, however, who has taken advantage of this provision by installing a series of 20 kW photovoltaic arrays adjacent to each other with separate accounts, each with zero or minimal load. We believe that this was done solely to take advantage of the retail buy-back rate, which would not be available to an independent power producer, which this customer essentially is. We propose that the closure of the CGS6 tariff to new accounts be effective retroactively to the date of this filing. Customers who have submitted valid applications for CGS6 on or before the date of this filing would be allowed on CGS6, but no new applications submitted after the date of this filing would be allowed.

Q Are you concerned that closing the CGS6 tariff to new customers retroactively to the date of this filing would be unfair to customers?

A No. The point of closing the CGS6 tariff to new customers rather than closing the tariff completely is to protect existing customers – both those with generation exceeding load occasionally and those who are abusing the spirit and intent of the tariff by providing substantial generation with zero or minimal load. No one would argue that the Commission lacks the authority to close this tariff completely in the course of this rate-case proceeding. If the Commission is unwilling to retroactively close the CGS6 tariff to new customers effective on the date of this filing, then the Company proposes that the CGS6 rate be closed completely, effective on the date of the order.

Q How do you propose to accommodate the customers with new renewable generation systems who would like to net meter their energy?

A We propose a new customer-owned generation tariff for net metering renewable generation. We would call this CGS8. This new tariff would require that the renewable generation be located on the customer's premise and it must be sized to offset the customer's full or partial load at that premise. We understand that there are seasonal variations with many renewable generation sources, particularly solar photovoltaic, so we would allow excess generation in one billing period to accrue so it may offset load in subsequent billing periods, up to one year. Accrued excess generation will expire upon the billing period that includes May 1 of each year; the accrued excess generation will reset to zero and the value of any such excess generation will be lost to the customer. It is expected that accrued excess generation would be close to zero on the reset date given the restriction that generation units should be sized to provide less than or equal to the customer's load at that premise. Excess generation that occurs in the billing period that includes May 1 of a given year will be accrued to offset load in subsequent months up to the billing period that includes May 1 of the following. May 1 was selected as the appropriate reset date because it is toward the beginning of the peak sunshine months, and there would be several months following the peak sunshine months for the accrued excess generation to offset load. A common reset date for all customers (as opposed to using each customer's installation date) would facilitate the billing process.

Q What changes are you proposing for CGS3?

A We are proposing to close the CGS3 tariff to new accounts. This tariff provides for customer owned generation to be dispatched by the Company. Given current market conditions, the likelihood of this generation being dispatched is low. Current customers on CGS3 may remain on this tariff, but the buy-back rates for both dispatched and non-dispatched energy will be based on the average forecasted LMP for the years 2013 and 2014 and the capacity credit will be based on the actual MISO market-clearing price for capacity in 2013. We are also proposing removal of some obsolete language in this tariff regarding load management credit.

Q What changes are you proposing for the CGS1?

A We are proposing a requirement that customers on CGS1 have internet access and web browser software that is compatible with the Company's price communication software.

Q What changes are you proposing for the CGS7 tariff?

A We are proposing the requirement that CGS7 accounts be time-of-use accounts.

Q Are there any other changes that you would like to make to the net-metering tariffs?

A Yes. We propose that the Commission grant the Company a waiver of PSC Administrative Code 113.0406(5) ("Budget Billing") to our net metering customers on tariffs, CGS 2, 4, 6, 7, and 8. We are requesting this because budget billing obscures the customer's monthly use and generation. With normal billing (that is, without budget billing) the customer can more readily see and understand the relationship between their generation and energy use, allowing customer behavior that would maximize the return on their investment in the renewable energy generator. Currently We Energies has no customers with net metered customer owned generation receiving budget billing.

Q Are you proposing to close any existing tariffs to new customers?

A Yes, we are proposing to close the Al1 alley lighting tariff to new customers.

Q Are you proposing to eliminate any programs or tariffs in this Docket?

A Yes, we are also proposing to eliminate the Cp2m interruptible tariff because it is redundant to have both it and the CpFN tariff. The only difference between Cp2m and CpFN is that CpFN allows for firm load and Cp2m does not, therefore, the elimination of the Cp2m tariff is not a reduction in service. Cp2m customers will automatically be shifted to CpFN with a zero firm-service level. We are also proposing to eliminate the Cp3A and Cg3A non-firm cooperative tariffs. These tariffs have already been replaced by Cp3S and Cg3S, respectively. We are also proposing to eliminate the general primary experimental real-time pricing tariff Cp1R. There are not any customers on this tariff and the more popular RTMP rider has replaced it. We are also proposing to eliminate the power enhancement equipment (PE1) rider. No customers are currently using this rider. We are also proposing to eliminate our Power Market Incentives – Pool voluntary load reduction program. This program was developed in the late 1990's in response to potential power shortages. The current capacity situation and the presence of the MISO market have eliminated the need for this. (We will continue to offer the Dollars for Power and Power Market Incentive programs to comply with §196.192(2) (a), although it is unlikely they will be invoked under the current capacity situation. We are revising language in the Dollar for Power tariff sheet to facilitate administration of the program.) We are also proposing to eliminate our Energy Partners residential central air conditioning load-control program. Again, given the current availability of capacity, this program is no longer cost effective. We are also proposing that the experimental peak-time rebate (PTR) rider and the experimental shift and save critical-peak pricing (CPP) option for residential and small general secondary customers be allowed to expire. Both of these experimental options were originally scheduled to expire on May 30, 2012, but we have received approval to remove the expiration dates from these tariffs. The availability clauses of both these experimental rates indicate that they are limited to areas where remote meter reading is readily available, technically feasible and cost beneficial. Based on experience with the first years of these offerings, we have determined that the existing remote meter reading system has technical and cost issues that render these rates inefficient. As the technology improves and our need for capacity increases in the future, we may want to implement these programs again. Our experience with these experiments and the experiences of other companies with similar programs will be beneficial at that time. Residential customers currently on the critical peak experimental tariffs would be shifted to the Rg3 time-of-use tariff unless they indicate some other preference and general secondary customers currently on the critical peak experimental tariff would be shifted to Cg6 time-of-use tariff unless they indicated some other preference. We intend to provide these customers with adequate warning of the tariff change so they may make informed decisions.

Q Have you done analysis of the impacts of the rate increases on customers, per filing requirements 23 and 24?

A Yes. The results of our analysis of the impacts of the new rates on customers are shown in Ex.-WEPCO/WG-Rogers-16, which compares our average rates for the past 20 years with various price indices.

D. Embedded Credits

Q Have you calculated the values for embedded credits for expansion of the electric distribution system?

A Yes. The calculated values of embedded credits for expansion of the electric distribution system are presented in Ex.-WEPCO/WG-Rogers-17.

Q How were the embedded credits calculated?

A The embedded credits were calculated in conformance with the Wisconsin Administrative code PSC113.1006. For residential and small general secondary classes this involves dividing the embedded cost of the distribution system for plant accounts 364 through 367 by the number of customers. An adjustment is made for three-phase customers, however, due to the fact that three-phase customers, in general, are larger than single-phase customers. A special calculation is made for accounts under the TE1 tariff. For large general secondary and general primary demand-rate customers the embedded credits are calculated by dividing the embedded cost of the distribution system by the average monthly billed demand. For street lighting customers the embedded credits are calculated by dividing the embedded cost of the distribution system by the number of lamps. Lamps, poles and spans for the area lighting rates Gl1 are not included because the costs of the distribution system for those customers are allocated to the residential, general secondary or general primary classes. Gl1 is excluded from the embedded credits. We have several street lighting schedules that are not billed on the basis of lamps, however, so we do not have a forecasted count of the lamps. For the purpose of calculating the embedded credit we have estimated the number of lamps by assuming an average lamp size of 125 watts consuming an average of 60 kWh per month.

E. Changes to Electric Rules, Regulations and Tariff Sheets

Q	Are you proposing any changes to the rules and regulations sheets and the rate sheets?

A	Yes. We are proposing numerous minor changes to the rules and regulations sheets and to the rate sheets. The proposed changes to the rules and regulations are presented in Ex.-WEPCO/WG-Rogers-18. The proposed rule changes include, but are not limited to, removing outdated references to disconnection fees, incorporating new embedded cost credits and language that would allow the Company to charge the customer to recover the cost of removal of service facilities from the customer's property when the removal is requested by the customer. (The Company's preferred practice is to abandon the facilities in place.) The proposed changes to the rate sheets (other than pricing changes) are presented in Ex.-WEPCO/WG-Rogers-19. The proposed rate changes include many minor administrative changes or clarification changes in addition to the more noteworthy changes previously addressed in testimony.

IV. Steam Utility

A. Steam Sales Forecast

Q. Please describe the exhibits you are filing in connection with the Steam Service application.

A The exhibits I'm sponsoring are listed below.

Ex.-WEPCO/WG-Rogers-1: Steam Sales Forecast

Ex.-WEPCO/WG-Rogers-2: Steam Cost-of-Service Unbundling Analysis

Ex.-WEPCO/WG-Rogers-3: Steam Revenue Yield and Embedded Credits

Ex.-WEPCO/WG-Rogers-20: Steam Rate Sheets

Q Would you describe the 2013 steam sales forecast used in the development of the Test Year information?

A Steam sales are projected to reach 1,916,281 MLbs in test year 2013 for the DMS service territory, and 722,912 MLbs for the WS service territory. Ex.-WEPCO/WG-Rogers-1 provides these forecasted values as well as forecasted 2012 sales actual historical sales on both Actual and Weather Normalized bases for both service territories.

Q When was the Test Year 2013 forecast developed?

A The DMS forecast used for TY2013 was prepared in August 2011 and uses historical billed sales data and weather through June 2011. The WS forecast for the TY2013 was prepared in February 2012 and uses historical sales and weather through December 2011.

Q What are the major drivers for historical variations and any changes to the forecast period?

A The DMS and WS steam territories are reasonably stable systems in terms of connections and disconnections, so the customer base is constant. For the forecast, specific customer additions or removals are included when substantively known. There have been notable reductions in steam usage across both territories. After adjusting for weather variances, DMS has experienced an approximate 105,000 MLB reduction in steam sales in 2011 relative to 2009. A similar comparison for WS shows a reduction that approaches 44,000 MLbs, which doubles when looking back to 2008. The steam forecast process attempts to identify the sizeable changes at the customer level and capture the trends for the forecast period.

Q What techniques are used to develop the steam sales forecasts?

A The forecasts use a combination of 3 statistical methods using ordinary least squares regression models. The first method is weather normalization of a base historical period and relies on relating monthly billed sales volumes with weather in order to quantify the effect of heating degree days (calculated at the base of 65 degrees, or HDD65), on monthly billed usage. A base forecast year is then determined to be the sum of the regression models' intercept (i.e. non-weather sensitive load) plus the value predicted by multiplying the weather sensitive coefficient by the expected "normal" weather values, which are the calculated average for the 1991 to 2010 period. This base is then extended into the forecast period for loads that are not expected to change. The second method uses the base forecast, but also incorporates expected volume changes of which we've learned from direct conversation with customers regarding planned facilities and operational changes. For these, specific adjustments are made to the historical base year for the particular forecasted years. The third method uses regression modeling that is different than the weather model in that it also includes a time-trend variable to estimate the effect efficiency improvements and conservation efforts that have been detected in recent historical loads. As the forecast is then a product of the model coefficients times expected future values for the weather and time, the efficiency and conservation effects are projected to continue in the future for a short period. Large customers in both service territories are modeled individually and the smaller customers in the DMS territory are aggregated into a group and modeled as one entity.

Q What is included in the steam sales forecast for the DMS service territory?

A The steam sales forecast for the Downtown Milwaukee steam service territory system is developed using a combination of all 3 forecast methods described above. The vast majority of customers fall into the group that is modeled as one entity and use the method that incorporates weather and a time-trend. Twenty-eight of the largest DMS customers are individually modeled. Of these, three customer forecasts use the simple weather normalization technique, eleven customer forecast incorporate the intelligence gained through direct customer contact, and fourteen forecasts use the method that incorporates weather and the time-trend. Weather Normalized sales to the DMS Ag-1 Rate class were 1,998,105 MLbs (1,930,230 Actual) in 2010, 1,973,333 MlLbs (1,944,550 Actual) in 2011, and we expect them to be 1,900,950 MLbs in 2012, and 1,885,576 MLbs in 2013. Sales beyond 2013 are assumed to be consistent at the 2013 level. There are not any planned increases in new customers, nor are there expected reductions due to business closure. Sales to existing customers on the Ag-4 Rate were 33,612 MLbs in 2010 and 34,634 MLbs in 2011. Ag-4 sales are projected to be constant at 30,705 MLbs in the forecast for 2012 and Test Year 2013. (Ag-4 is not adjusted for weather.) The forecasted sales to the two existing customers in Ag-4 were based upon recent history and information regarding customer specific plans.

Q What is included in the steam sales forecast for the WS service territory?

A The steam sales forecast for the Wauwatosa steam service territory is a summation of individual forecasts that have been prepared on a customer basis. WS customers fall into two distinct groups, the first being the one customer that takes service right at the steam plant, WISVEST Thermal Energy Systems, and the second group is comprised of all the other customers. This second group not only takes steam from the production facility, but also uses the distribution system. The 2012 forecast and 2013 Test Year forecast for WISVEST relies exclusively on the customer's own forecast for purchased steam. The forecast for sales to WISVEST in 2012 and Test Year 2013 has thus been set at 198,000 MLbs. The 29 customers that require the distribution system have been individually modeled and forecast with the weather normalization method as previously described. Weather Adjusted sales to this group of customers were 582,972 MLbs (569,236 Actual) in 2010 and 559,145 MLbs (552,368 Actual) in 2011. Sales for this group of customers are projected to be 552,638 MLbs in 2012 and 524,912 in 2013. The decrease between 2012 and the Test Year is planned to occur because four customers that are West of US Hwy 45 are set to disconnect from the steam loop and will not be reconnected after the highway reconstruction, and a fifth customer that is east of the highway is expected to switch to natural gas for heating. In total, the reduction beginning in 2013 is expected to be 27,726 MLbs.

B. Steam Cost of Service Study

Q Have you performed a cost-of-service unbundling analysis for your steam utility?

A Yes. The results of the steam cost-of-service study are presented in Ex.-WEPCO/WG-Rogers-2. This shows how costs are categorized into production and distribution functions. The first page is basically a restatement of the Operating Income Statement and Revenue Deficiency Calculation presented by Company witness Mr. David Ackerman in Ex.-WEPCO/WG-Ackerman-1 Schedule 6. I have restructured those documents to make it easier to unbundle to production and distribution functions. The unbundled values are shown on pages 2 and 3.

Q What assumptions did you make in the unbundling process?

A I assumed all general plant was related to steam distribution and administrative and general O&M costs were proportional to the non-fuel O&M costs. I allocated all taxes on rate base.

Q Why did you need to unbundle the steam costs?

A The costs must be unbundled because there are separate rates for production and distribution. The steam production costs are closely related to the energy produced at the power plants, as steam production is a by-product of electric production. Distribution costs, on the other hand, are more a function of the peak demand because the distribution system must be sized to meet the peak demand. In order to reflect this cost causation in our rates, we may at some time propose to base the production rates on each month's actual energy consumption and the distribution rates on monthly energy consumption ratcheted over twelve months. Having separate production and distribution rates would make this future step easier. Unbundling of steam rates is important to WS because there is one large customer in WS that takes steam service directly from the production plant and therefore is not charged the distribution rate. All existing customers in DMS are charged for both production and distribution, but the Ag2 tariff is designed for the customer to take service directly from the production plant.

C. Steam Rate Design

Q Are you proposing adjustments to the current steam rates?

A Yes. The proposed steam rate design and revenue yield calculations are shown in Ex.-WEPCO/WG-Rogers-3 Schedule 1. We are proposing that the rate adjustments be phased in over a two-year period, with roughly half the adjustment occurring in 2013 and the other half in 2014.

Q How are the facilities charges calculated?

A The facilities charge should cover the customer-related costs, including metering, billing and other miscellaneous costs. We are proposing to maintain the current facilities charges. These charges adequately cover the customer-related costs for DMS Ag1 and Ag4 and for WS. In the previous rate case (05-UR-104) we proposed that the facilities charge for Ag2 be set to that for Ag4 because we anticipate substantial administrative costs for Ag2. The Commission agreed with the intervener who argued that the Ag2 facilities charge should be set to that for Ag1. We anticipate arguing for a higher facilities charge for Ag2 in some future rate case when we have some actual experience; however we will not do so in this Docket.

Q How are the Ag1 energy charges calculated?

A The Ag1 energy charges are calculated by simply dividing the production costs and distribution costs, derived in Ex.-WEPCO/WG-Rogers-2 by the relevant forecasted annual energy. The revenue generated by the facilities charge is subtracted from the distribution costs before this calculation. For DMS the total of Ag1 and Ag4 forecasted energy is used in the initial calculation. An adjustment is made to the Ag1 production rate to account for the Ag4 non-firm credit.

Q How is the interruptible credit for the Ag4 rate calculated?

A The interruptible credit for Ag4 is derived in Ex.-WEPCO/WG-Rogers-3 Schedule 1 Page 5. First the value of the interruptible steam load is calculated based on the value of the electric capacity that could be increased. The levelized annual cost of a combustion turbine is used as the basis for the value of electric capacity. This is similar to the way we calculate credits for non-firm electric customers. One key to this calculation is the relationship between steam production and electricity production. For this analysis, we assume that every thousand pounds of steam diverted from the electric generator turbines each hour reduces the potential electric production of the power plant by 70 kilo Watts. Another key assumption for this calculation is the diversity factor of the Ag4 customers. The interruptible load is only valuable to the electric utility if it is available when it is needed. The diversity factor provides an estimate of the probability that the load will be available when needed. The unit value of the interruptible steam load would be subtracted from the firm steam production rate calculated for Ag1 to calculate the non-firm steam production rate. A final check is then made, however, to make sure that the non-firm steam production rate is not lower than the average fuel cost. If the calculated non-firm steam production rate is lower than the average fuel cost the non-firm steam production rate would be set to the average fuel cost. The value of the non-firm load is calculated to be $1.26746/MLbs.

Q How are the Ag2 energy charges and condensate credits derived?

A The production energy charge is set equal to the Ag1 production energy charge, as it was ordered in Docket 05-UR-104. There is no distribution energy charge because Ag2 customers must take service directly from the production plant. The condensate return credits reflect the value of the water returned to the power plant. The values for the condensate credits are set to the same values approved in Docket 05-UR-104.

Q Have you done an analysis of the customer impacts of the new steam rates?

A Yes. Since the vast majority of the revenue is derived from the energy charge, each Ag1 customers' impact would be roughly the same as the average percentage impact for the respective service territory. Ag4 customers will have slightly higher percentage impact than DMS Ag1 customers due to the lower base from which their percentage increase is calculated.

D. Steam Rules and Regulations

Q Are you proposing any changes to the rules and regulations for steam rates?

A Yes. We have made some minor updates to remove outdated references in the steam rules and regulations.

Q Are you proposing any changes to the fuel cost adjustment procedures?

A No. We propose to continue the current fuel cost adjustments procedures.

Q Have you calculated new values for embedded credits for expansion of the steam distribution systems?

A Yes. The calculated values of embedded credits for expansion of the steam distribution systems are presented in Ex.-WEPCO/WG-Rogers-3 Schedule 2.

Q How were the embedded credits calculated?

A The embedded credits for the steam distribution system were derived in a manner similar to that prescribed for electric embedded credits in PSC 113.1006. The PSC rules for steam in PSC 140 do not address embedded credits. The depreciated costs of the steam distribution systems are divided by the total steam sales using the distribution system.

Q Are you proposing any changes to the embedded credit rules?

A No.

Q Does this conclude your testimony?

A Yes.